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November 30, 2015

- Via Email and Federal Express -

Darrell Nitschke, Executive Director
 North Dakota Public Service Commission
 State Capitol Building, Dept 408
 600 East Boulevard
 Bismarck, ND 59505-0480

RE: NEGOTIATED AGREEMENT
 CASE NOS. PU-12-813, 13-706, 13-707, 13-708, 13-742 13-743, 13-194, 13-195, 15-96

Dear Mr. Nitschke:

Northern States Power Company, doing business as Xcel Energy, respectfully submits testimonies of Company Witnesses Christopher B. Clark, Kurtis Haeger, and David H. Sederquist in support of the Negotiated Agreement that was filed jointly with staff on September 30, 2015.

As the Commission may recall, the Negotiated Agreement addresses jurisdictional generation resource policy differences, as contemplated in the Settlement Agreement in the Case PU-12-813. The testimony supports the goals and discusses the following key items included in the Negotiated Agreement:

- Acceleration of the Company's commitment to locate thermal generation in the state from 2036 to end-of-year 2025.
- Exclusion of seventeen existing CBED and small solar purchased power agreements from the Company's North Dakota Fuel Cost Rider.
- Extension of the current electric rate moratorium by one additional year (i.e., through 2017).
- Continued recovery in North Dakota of six existing biomass purchased power agreements subject, in part, to a sizeable refund (estimated to be

116 **PU-13-708** Filed: 11/30/2015 Pages: 24
 Pre-filed direct testimony of David Sederquist in support of negotiated agreement

117 **PU-13-706** Filed: 11/30/2015 Pages: 24
 Pre-filed direct testimony of David Sederquist in support of negotiated agreement

117 **PU-13-707** Filed: 11/30/2015 Pages: 24
 Pre-filed direct testimony of David Sederquist in support of negotiated agreement

256 **PU-12-813** Filed: 11/30/2015 Pages: 24
 Pre-filed direct testimony of David Sederquist in support of negotiated agreement

120 **PU-13-742** Filed: 11/30/2015 Pages: 24
 Pre-filed direct testimony of David Sederquist in support of negotiated agreement

128 **PU-13-743** Filed: 11/30/2015 Pages: 24
 Pre-filed direct testimony of David Sederquist in support of negotiated agreement

135 **PU-13-195** Filed: 11/30/2015 Pages: 24
 Pre-filed direct testimony of David Sederquist in support of negotiated agreement

118 **PU-13-194** Filed: 11/30/2015 Pages: 24
 Pre-filed direct testimony of David Sederquist in support of negotiated agreement

103 **PU-15-96** Filed: 11/30/2015 Pages: 24
 Pre-filed direct testimony of David Sederquist in support of negotiated agreement

Direct Testimony
David H. Sederquist

Before the North Dakota Public Service Commission
State of North Dakota

Northern States Power Company 2013 Electric Rate Increase Application	Case No. PU-12-813
Northern States Power Company Advanced Determination of Prudence – Courtenay Wind Project Application	Case No. PU-13-706
Northern States Power Company Advanced Determination of Prudence – Odell Wind Project Application	Case No. PU-13-707
Northern States Power Company Advanced Determination of Prudence – Pleasant Valley Wind Project Application	Case No. PU-13-708
Northern States Power Company Advanced Determination of Prudence – Border Winds Project Application	Case No. PU-13-742
Northern States Power Company 150 MW Border Winds Project – Rolette County Public Convenience and Necessity	Case No. PU-13-743
Northern States Power Company Advanced Determination of Prudence – NG Generators Application	Case No. PU-13-194
Northern States Power Company Red River Valley NG Units 1 & 2 – Hankinson, ND Public Convenience and Necessity	Case No. PU-13-195
Northern States Power Company Advance Determination of Prudence – 345 Mankato Energy Center Application	Case No. PU-15-96

Negotiated Agreement

Exhibit__ (DHS-1)
November 30, 2015

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1 Q. DO YOU HAVE ANY PRELIMINARY COMMENTS YOU WANT TO MAKE ABOUT
2 THE AGREEMENT?

3 A. Yes I do. I'd like to start by saying that back in December of 2013 when the
4 Staff and NSP committed to the effort of developing a regulatory framework
5 that would result in electric generation costs being reflective of the
6 Commission's policy preferences, we had a very ambitious vision. Today,
7 we remain committed to such a resource framework, but we have become
8 much more attuned to the difficulties in balancing the requirements – and
9 benefits – of an integrated system with meeting the policy requirements of
10 the states in which we operate.

11

12 That said, we submitted an Agreement on September 30th that maintains our
13 momentum toward what we are referring to as a long-term Resource
14 Treatment Framework (RTF). In doing so, the Agreement focuses primarily
15 on a solution for treating *existing* generation resources that the Staff flagged
16 during our last rate case as not being consistent with North Dakota energy
17 policies. As a result, this Agreement resolves some of the longstanding
18 Commission concerns about the prudence of legacy wind and solar
19 resources that came about through policy objectives in Minnesota but were
20 recovered in North Dakota to date, and it also creates the path and
21 commitment for the Company's first investment in thermal generation in
22 North Dakota in many decades.

23

24 Developing an approach to selecting future energy resources that is
25 responsive to differing state energy policies has been – and will continue to
26 be – a complex and measured effort. In that regard, I'd like to acknowledge
27 the patience, flexibility, and constructive approach demonstrated by

1 Advocacy Staff throughout this process of reinventing a different framework
2 to jurisdictional resource planning and cost recovery. They have been
3 receptive to the weighty challenges we have come up against, but have
4 continued to be engaged and offer ideas while remaining true to their and
5 the Commission's original objectives.
6

7 II. PROVISIONS OF THE AGREEMENT

8

9 Q. WHAT ARE THE KEY ELEMENTS OF THIS AGREEMENT?

10 A. If approved by the Commission, this Agreement will result in the following:

- 11 • *By the end of 2025, Xcel Energy will build or have located in North Dakota a*
12 *natural gas-fired electric generation facility with a capacity of at least 200 MW:* The
13 Company commits to accelerate by 11 years its Comprehensive
14 Settlement (Case No. PU-12-813) commitment to construct, by 2036, an
15 NSP System thermal generating plant in North Dakota. Our revised
16 2015 Resource Plan points to the need in the early to mid-2020's for
17 additional capacity, and our preliminary analysis shows that a plant in
18 eastern North Dakota could be reasonably cost-effective and enhance the
19 reliability of the NSP System and more specifically, its North Dakota
20 service territory.
- 21 • *The additional costs of 17 existing power purchase agreements (PPAs) will no longer*
22 *be recovered in North Dakota:* In recognition that the energy policies in
23 other states in which Xcel Energy operates have and may continue to
24 diverge from the energy priorities of North Dakota, the Negotiated
25 Agreement provides for the exclusion of certain Community-Based
26 Energy Development (CBED) and small solar PPAs from the Company's
27 North Dakota Fuel Cost Rider (FCR). This provision recognizes that

1 these resources were planned and selected to meet commitments and
2 requirements established in and for the state of Minnesota. This
3 provision also acknowledges that, while the Commission initially allowed
4 the costs of these relatively small projects to be recovered in NSP's
5 North Dakota rates, over time the number and impact of these projects
6 on North Dakota rates has grown to a material level and, given that the
7 aggregate effect conflicts with North Dakota's energy policies, the
8 premium costs (approximately \$1.6 million beginning in 2016 and a total
9 of approximately \$19 million through 2030) will be removed from rates.

- 10 • *The costs of six key biomass energy contracts will continue to be recovered in North*
11 *Dakota:* In the Comprehensive Settlement, six baseload-type biomass
12 resources from which NSP purchases energy and capacity were identified
13 as potential PPAs for exclusion. Given the close ties these resources
14 have with the approval of additional nuclear fuel storage – and the
15 continued operation of the Company's low-cost Prairie Island units –
16 Staff has agreed to allow the continued recovery until the terms of these
17 PPAs expire.
- 18 • *The Company's current rate case moratorium will be extended an additional year:* In
19 the Comprehensive Settlement, a four year rate plan was approved which
20 included annual base rate increases of 4.9 percent in 2013, 2014, and
21 2015, and a rate freeze in 2016. If approved, this agreement will extend
22 the freeze through 2017. As a result, NSP will not be allowed to increase
23 base electric rates (on an interim or final level) before January 1, 2018.
- 24 • *Commission Staff will support NSP's continued use of a 12 Coincident-Peak system*
25 *allocator through 2025 for the purpose of assigning production and transmission costs*
26 *to its three NSP operating company jurisdictions:* This Comprehensive
27 Settlement called for an in-depth study of the method alternatives for

1 allocating the costs of the integrated NSP System (generation and
2 transmission) costs to its state jurisdictions. The study was conducted by
3 a third-party consultant (the Brattle Group) under the direction of both
4 Parties to the Settlement, and submitted to the Commission on April 27,
5 2015. This Agreement applies the results and recommendations of the
6 study to the positions taken by Advocacy Staff and NSP in any applicable
7 electric rate proceedings initiated prior to December 31, 2025.

- 8 • *Development of a Resource Treatment Framework:* Recognizing that the other
9 terms of the Negotiated Agreement do not fully resolve the issue of
10 divergent state energy policies on a going-forward basis, we are obligated
11 to file with the Commission a RTF that will propose how to address this
12 issue into the future.

13
14 Q. WHAT WILL BE THE IMPACT OF THIS AGREEMENT ON NORTH DAKOTA
15 ELECTRIC RATES?

16 A. The immediate effect of the Agreement will be to decrease overall electric
17 rates by approximately \$1.6 million in 2016. It will also prohibit an electric
18 base rate increase until at least 2018. Finally, the Agreement requires that
19 the combustion turbine we committed to be located in the state be treated as
20 an NSP System resource; this means the costs are to be allocated to all states
21 and customers served by the NSP System, as is customary. As a result,
22 approximately 5 percent of the project costs will be assigned to North
23 Dakota customers (subject, of course, to any provisions of a future approved
24 RTF that may modify this arrangement).

25
26

1 Q. SINCE THIS AGREEMENT FOCUSES PRIMARILY ON HOW TO TREAT CERTAIN
2 *EXISTING* GENERATION RESOURCES THAT STAFF IDENTIFIED AS NOT
3 REFLECTIVE OF A LEAST-COST, NEED-BASED PLANNING APPROACH DOES THE
4 AGREEMENT ADDRESS THE TREATMENT OF *FUTURE* RESOURCE ADDITIONS
5 IN ANY WAY?

6 A. Yes it does, and mainly in two ways. First it identifies the reasons why the
7 Parties to this Agreement believed it prudent to first address the treatment
8 of existing resources and provide additional time for the more difficult task
9 of developing an overall, long-term RTF. Second, it identifies a potential
10 timeline for the RTF; a due date for filing the proposal of January 1, 2017, 8
11 to 10 months in 2017 for the Commission to conduct their review, and a
12 proposed implementation date of January 1, 2018.

13

14 Q. WHY DIDN'T THE PARTIES INCLUDE AN RTF, OR LONG-TERM SOLUTION, IN
15 THIS AGREEMENT?

16 A. There are primarily two reasons why. First, there is considerable future
17 uncertainty in the energy industry. This stems mainly from the evolving
18 utility landscape we are facing and emerging Federal environmental
19 requirements such as the Environmental Protection Agency's (EPA) Clean
20 Power Plan. In addition, there are – or may be – differing state
21 environmental regulations as well. Moreover, NSP's baseload generation
22 fleet will be changing dramatically in the next 10-20 years. Even the
23 Midcontinent Independent System Operator (MISO) is contemplating
24 changes to how it defines its load zones and determines its adequacy
25 requirements. There are many moving parts and they all give us good reason
26 to pause as we consider how to construct a new regulatory paradigm for
27 approving resources in the future.

1 Second, in the many months we have been working on this issue we have
2 learned much about the significant complexity in designing a framework to
3 meet the unique energy policy preferences of the various states we serve
4 while maintaining a multi-state, integrated system. Though it was our goal
5 from the start, it became more and more evident that it was simply not
6 feasible to adequately address the myriad of issues in time to meet the filing
7 deadline for this Agreement. More time to analyze different options and
8 assess the cost/benefit ratios of those options was, and is, clearly needed.
9

10 III. THE PATH TO THE AGREEMENT

11
12 Q. PLEASE DESCRIBE THE PROCESS THAT RESULTED IN THIS AGREEMENT.

13 A. Once the Commission approved the Comprehensive Settlement in Case No.
14 PU-12-813, we, along with Staff, began in earnest to explore options for
15 addressing the impact of divergent state energy policies, wherever they may
16 occur, on electric rates in our system footprint. A team was commissioned
17 to draw upon various areas of Company and outside expertise to brainstorm
18 various framework alternatives, what steps would need to be taken and in
19 what timeframe, and what potential obstacles there would be to implement
20 each scenario.
21

22 Q. WHAT FRAMEWORKS WERE CONSIDERED?

23 A. The most serious consideration was given to the following ideas:

- 24 1. *States ensure full cost recovery for resources that they direct Xcel Energy to acquire and/or*
25 *otherwise approve.* This would entail a process whereby there is assurance at
26 the front end of the resource approval process that the full capacity, energy,
27 any environmental attributes, and related cost recovery of prospective

1 resources being approved or directed in certain states be assigned and
2 accepted only in those approving states for planning, accounting, and
3 ratemaking purposes.

4 2. *Uneconomic resources are repriced in those states relying on least-cost selection criteria.* In
5 this approach, NSP would use a “least cost proxy” to reprice, for
6 ratemaking, future resource additions whose selection is not approved by the
7 reviewing state commission.

8 3. *Employ a Pricing Zone concept.* This would entail establishing separate pricing
9 zones for North Dakota and the remainder of the integrated NSP System.
10 This would allow for our North Dakota customers to be served by
11 generation resources that were consistent with the Commission’s policy
12 preferences, our North Dakota customers would no longer be directly
13 served by the integrated NSP System.

14 4. *Restructure Xcel Energy to facilitate more state autonomy in selecting resources.* With
15 this approach, a separate operating company subsidiary of Xcel Energy
16 would be established to serve our North Dakota loads and better facilitate
17 separate regulatory processes and power contracting that would comply with
18 each states’ energy preferences. This approach would take the pricing zone
19 concept one step further to legally separate our North Dakota operations
20 from the NSP-Minnesota company and the integrated NSP System..

21
22 None of these outcomes have advanced much past the conceptual stages,
23 but the discussions that ensued over many months regarding how to address
24 the impact of divergent state energy policy on each states’ rates also involved
25 Xcel Energy’s senior management team. It has been an important and
26 strategic issue at the highest levels of our company.

27

1 Q. WHY WASN'T NSP ABLE TO DEVELOP A FRAMEWORK OUT OF THE FIRST
2 APPROACH THAT YOU MENTION?

3 A. Establishing a process for this "front end" understanding would be very
4 difficult without additional time. Our review of the regulatory processes in
5 place today in each state, and the complexity of trying to coordinate them in
6 a way to achieve full accord - or even understanding of the impact on
7 customers - among the affected states on each and every resource decision
8 led us to see that such a process really requires a "regional" regulatory
9 approach to resource selection and approval. The various forms of
10 regulatory approval needed in each NSP state would have to be closely
11 aligned so as to ensure commission procedures were fairly consistent and
12 made on a similar timeframe. There would also need to be an ability for
13 states or Xcel Energy to reopen dockets to consider the subsequent
14 decisions made by the other state commissions. Even if it were feasible for
15 us to bring about a more consistent set of state approval processes (which
16 would involve various regulatory rule reforms and passage of new
17 legislation), this approach has the potential to create long regulatory delays,
18 more litigation, and increased costs.

19
20 In summary, while this path shows some promise over the long term, there
21 is significant interjurisdictional coordination that would be required as well
22 as the need to address the appropriate approval procedures in each state
23 going forward.

24
25
26

1 Q. WHY HASN'T NSP BEEN ABLE TO FURTHER DEVELOP THE REPRICING
2 APPROACH?

3 A. At first blush, this method does appear to be quite feasible and actually
4 formed the basis of the Comprehensive Settlement's "Restack" concept.
5 But as with many things, the devil is in the details. The first complication is
6 getting agreement about how to reprice the capacity and energy components
7 of the resource. To determine a least-cost proxy price, does one use existing
8 generation assets, rely on some MISO benchmark, or construct a theoretical
9 generation resource? Should the proxy be updated every year to reflect new
10 technical developments or economic realities? These are only two questions
11 of many that need to be answered and agreed upon.

12
13 And, again, what about the administration and accounting needed to track
14 each and every repriced PPA and/or generation addition that comes down
15 the road? You can imagine the complexity and detail in tracking the various
16 fixed and variable costs throughout the operating or contract lives of the
17 affected resources, to say nothing of the impacts to the ratemaking process.

18
19 These illustrate some of the technical challenges, but ultimately there is
20 another over-arching problem with this approach: Xcel Energy would rarely,
21 if ever, be able to fully recover its cost of service without full inter-
22 jurisdictional coordination to ensure costs not recovered through a repricing
23 approach are recovered in the cost-causative jurisdiction.

24
25
26

1 Q. WHAT IS THE "PRICING ZONE" ALTERNATIVE, AND WHY HASN'T THAT BEEN
2 MORE FULLY DEVELOPED?

3 A. This concept would essentially remove the generation component of our
4 service to North Dakota customers from the integrated NSP System. Under
5 this approach, our North Dakota customers would be served by resources
6 selected only for North Dakota and approved by the Commission. These
7 resources would be appropriately sized for a 500-600 MW utility. As older
8 units on our NSP System are gradually retired and replaced, our North
9 Dakota customers would not participate in their replacement but instead a
10 North Dakota-specific resource would be acquired to replace the North
11 Dakota share of the retired capacity.

12

13 The Parties spent considerable time discussing, at a high level, this concept.
14 We intend to continue analyzing this concept as we work through
15 developing an RTF. However, we are concerned that this approach could be
16 detrimental to North Dakota customers as they lose the benefits inherent in
17 the integrated NSP System.

18

19 Q. FINALLY, PLEASE COMMENT ON THE ALTERNATIVE OF RESTRUCTURING XCEL
20 ENERGY.

21 A. Generally speaking, establishing a separate operating company (OpCo) for
22 the Xcel Energy's North Dakota operations would, in fact, help to resolve a
23 number of regional regulatory coordination issues that a multi-state utility
24 like NSP must deal with. It would also facilitate the negotiation of separate
25 power supply contracts and arrangements for our North Dakota operations,
26 much like a wholesale supply contract to a municipality or another utility
27 company. However, the process for establishing a North Dakota OpCo is

1 expensive and very time-consuming as it involves a number of federal and
2 state approvals, the renegotiation of many supplier and affiliate contracts and
3 agreements, certificate transfers, and other significant transactions. I think it
4 would be fair to characterize this option as a “last resort” given the
5 magnitude of effort and cost, and its “finality”. The Company has hopes
6 that a simpler and more flexible framework can be developed. However, as
7 we work through the RTF we want to keep this option available.
8

9 Q. IF XCEL ENERGY REALIZED LAST SUMMER THAT THIS AGREEMENT WOULD
10 NOT INCLUDE A MORE COMPLEX LONG-TERM RTF PROPOSAL, WHY DID YOU
11 NEED TO REQUEST A THREE MONTH EXTENSION OF TIME TO FILE WITH THE
12 COMMISSION?

13 A. In early June of this year, negotiations between the parties led to a very
14 promising verbal agreement that would resolve, in a fairly efficient manner,
15 how to treat the existing renewable PPAs listed in the Comprehensive
16 Settlement identified by Staff as “uneconomic” resources needing to be
17 repriced. The key to this verbal “agreement in principle” was Xcel Energy’s
18 offer to consider accelerating its 2036 commitment to build a North Dakota
19 thermal generating plant to as early as 2020.
20

21 Up to this point in time, much of the discussions had focused on proxy
22 pricing concepts and ways in which Xcel Energy could migrate its North
23 Dakota system to be more “stand alone” in terms of the Commission being
24 able to influence the types of future energy resources added to meet North
25 Dakota load growth and replace retired plants. But the verbal agreement
26 reached in June narrowed the focus to the ratemaking treatment of the
27 existing renewable PPAs listed in the Settlement and how to frame the

1 commitment to locate a plant in North Dakota. Even so, it was evident that
2 more time would be needed for us to explore various thermal plant options.
3 It was the need for due diligence on this effort that prompted our request
4 for more time to file the Agreement.
5

6 Q. WHY DID THE GENERATION COMMITMENT CHANGE FROM 2020 IN YOUR
7 JUNE VERBAL AGREEMENT TO 2025 IN THE FILED AGREEMENT?

8 A. There were two primary reasons for this change. First, the Company's
9 concerted efforts in July and August to investigate potential generation
10 investments and structures in North Dakota soon revealed that the logistics
11 of determining an investment structure, siting the plant, arranging for its fuel
12 supply and interconnection, and completing construction simply could not
13 be accomplished by the end of 2020. Second, during the summer we had
14 already begun to make sizeable investments toward the 200 MW combustion
15 turbine planned and approved for our Black Dog site and that we would
16 move ahead on the installation of the Black Dog unit first as the most cost
17 effective resource available to meet needs prior to 2025. Staff was amenable
18 to 2025 as the "outside" target date so we agreed to that. Mr. Haeger
19 discusses the need drivers around the 2025 date.
20

21 Q. ARE ANY OF THE LONG-TERM ALTERNATIVES YOU'VE DISCUSSED HERE
22 CONSIDERED TO BE "OFF THE TABLE" AS FAR AS FUTURE DISCUSSIONS
23 AROUND AN RTF GO?

24 A. No, I don't think so. Mr. Clark discusses the Company's openness to all
25 solutions for an RTF. But the challenges posed by each of them – as well as
26 the uncertainties of the evolving utility landscape, including environmental
27 regulations and generation technologies – provide good justification for not

1 rushing to include a framework for long-term, forward looking proposals in
2 this Agreement. The Negotiated Agreement requires us to continue to work
3 on developing an RTF in 2016 and file a future-looking proposal with the
4 Commission by January 1, 2017. I might add that, until and unless an RTF
5 has been approved, the Commission retains its ability to review (and reject)
6 resources proposed by NSP. We acknowledge that the current status quo
7 may be unsustainable and, therefore, moving away from the current status
8 quo provides incentive for Xcel Energy to develop and propose an appealing
9 long-term solution through the RTF.
10

11 **IV. BENEFITS OF THE NEGOTIATED AGREEMENT**

12

13 **A. Commitment to Build Generation in North Dakota**

14 Q. WHAT IS THE VALUE OF NSP'S COMMITMENT TO ADD DISPATCHABLE
15 GENERATION IN NORTH DAKOTA?

16 A. I see our commitment to locate dispatchable thermal generation in the state
17 as a door-opener for future investment by the Company in the state's robust
18 energy industry. Depending on the ultimate size and scope of the plant,
19 once it is built Xcel Energy will have invested nearly \$1 billion in low-cost
20 North Dakota generation and transmission assets during the most recent
21 fifteen years, including almost \$600 million in new wind generation.
22

23 Infrastructure build-out can lead to more economic activity and more
24 infrastructure build-out. I can envision that a plant or large energy park in
25 eastern North Dakota could act as a catalyst for one or more natural gas
26 supply lines from the west to the east, which of course could help the
27 economic development efforts of a number of small communities along the

1 route. Such a new pipeline would have a favorable impact on the economics
2 of converting the plant at some point in the future to a larger and more
3 efficient combined-cycle facility.

4
5 We have seen how a generating plant of this type and the enhanced reliability
6 it brings is an enticement to national businesses looking to locate new and
7 large manufacturing, data processing, or food processing facilities in North
8 Dakota. I can envision that such a plant could be expanded in the future as
9 a competitive, brown-field resource option similar to the advantageous
10 economics of Calpine's Mankato Energy Center. And of course, all of these
11 possibilities bring to North Dakota additional jobs, economic growth, and
12 new tax revenues.

13
14 Q. IS NSP'S COMMITMENT TO CONSTRUCT THERMAL GENERATION IN EASTERN
15 NORTH DAKOTA CONDITIONED?

16 A. To an extent, yes. As with any generation development, we must obtain all
17 necessary permits and approvals to construct the plant. And even if we
18 assume that all North Dakota regulatory and local zoning approvals will be
19 granted, our other state jurisdictions, in particular Minnesota, have regulatory
20 processes that require us to obtain their approval prior to adding resources
21 to our system.

22
23 Q. HOW WILL THE COMMISSION HAVE ASSURANCE THAT XCEL ENERGY WILL
24 FOLLOW THROUGH WITH THIS COMMITMENT IF THESE CONDITIONS ARE NOT
25 MET?

26 A. Staff was concerned about this and proposed, and we agreed, to subject to
27 refund half of the revenues associated with the continued cost recovery of

1 six biomass PPAs from 2016 through 2025. The refund is triggered if the
2 plant is not in-service by December 31, 2025 without qualification (provided
3 that we can always petition the Commission for an extension, or
4 modification, if necessary).

5
6 **B. Exclusion of Certain Renewable PPAs from Rate Recovery**

7 Q. WHAT IS THE VALUE OF EXCLUDING 15 CBED PROJECTS AND 2 SMALL
8 SOLAR PPAs FROM THE NORTH DAKOTA FCR?

9 A. We estimate that excluding these 17 PPAs from the monthly North Dakota
10 Fuel Cost Rider (FCR) charge will reduce North Dakota customer energy
11 costs starting at about \$1.6 million in 2016.

12
13 Q. HOW ARE THE SIX BIOMASS PPAs LISTED ON ATTACHMENT E IN THE
14 COMPREHENSIVE SETTLEMENT BEING TREATED?

15 A. The Company will continue to include these costs in its FCR as they have
16 been since these resources went into production on various dates from 1994
17 to 2009. As such, there will be no future incremental increase in North
18 Dakota electric rates as a result of these PPAs.

19
20 Q. WHAT IS THE RATIONALE FOR HAVING NORTH DAKOTA CUSTOMERS
21 CONTINUE TO PAY FOR THE BIOMASS RESOURCES?

22 A. These resources represent approximately 145 MW's of baseload-like power
23 that have been a part of the NSP System, and recovered in North Dakota
24 retail rates, for many years. The projects were developed and the power sold
25 to Xcel Energy so NSP could comply with legislation passed in Minnesota in
26 the early 1990's that also allowed us to temporarily store spent nuclear fuel at
27 our 1,100 MW Prairie Island nuclear plant. Obtaining the certificate to store

1 spent fuel at the site meant that we could continue to operate these units for
2 an additional 20 years. The Commission has always supported our nuclear
3 plants as they have been reliable, low-cost, and clean sources of power, and
4 these PPAs are tied to our ability to continue to provide nuclear energy now
5 and many years into the future.
6

7 **C. Additional Year of Rate Moratorium**

8 Q. WHAT IS THE VALUE OF ADDING ANOTHER YEAR TO THE CURRENT 2016
9 RATE MORATORIUM?

10 A. In Case PU-12-813 the Commission approved NSP's first 4 year "multi-year
11 plan" (MYP) which established fixed percentage rate changes for each of
12 2013, 2014, and 2015, (4.9 percent, or about \$10 million annually) and a rate
13 "freeze" in 2016. It is somewhat difficult to be specific with respect to the
14 financial impacts of adding another year to the moratorium given that we do
15 not have a "rate case quality" forecast for 2017. However, it would seem
16 reasonable to say that extending the freeze another year has the potential to
17 save North Dakota customers millions of dollars in interim and/or final rate
18 increases, not to mention the costs to conduct another rate proceeding in
19 2017. When the Comprehensive Settlement was submitted in 2013, we felt
20 there was a reasonably good chance that we would need to prepare another
21 rate case to file in late 2016 using a 2017 test year. With this agreement,
22 however, NSP would defer such a filing another year.
23
24
25
26
27

1 **D. Demand Allocator**

2 Q. WHY IS THERE A PROVISION IN THE AGREEMENT THAT STAFF WILL SUPPORT
3 USE OF THE 12CP DEMAND ALLOCATOR THROUGH 2025?

4 A. I believe Staff was comfortable with the findings and recommendations of
5 the Allocation Study we filed with the Commission on April 27, 2015. The
6 Study thoroughly evaluated a number of methodologies based on their
7 representation of costs, stability, forecastability, simplicity, and overall
8 system cost recoverability and we were both satisfied that the current
9 methodology in place – that of the 12 coincident peak – was reasonably
10 adequate for ensuring that North Dakota customers were paying their fair
11 share of NSP’s system generation and transmission costs.

12
13 In addition, both Parties agreed that establishing some regulatory certainty
14 would help to mitigate the number of issues that the Commission and
15 Company will need to address in the next 5-10 years.

16
17 Q. DOES THIS MEAN THAT THE COMMISSION IS PROHIBITED FROM ADDRESSING
18 THE JURISDICTIONAL ALLOCATION ISSUE UNTIL 2026?

19 A. No, I don’t believe that is what the Agreement calls for. Rather, the Parties
20 are agreeing to both support use of the 12 CP method in any future rate
21 filings through 2025. That doesn’t preclude the Commission or other
22 interested parties from reviewing or challenging its use in a future rate
23 application.

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1 extends the current NSP electric rate freeze another year, 3) commits NSP to
2 make a significant investment in a North Dakota generating plant to help
3 meet its future system capacity needs, and 4) sets the timing for the
4 establishment of a long-term Resource Treatment Framework to address in a
5 more comprehensive manner the future rate and regulatory impacts of
6 divergent state energy preferences and policies. For these reasons, I
7 recommend the Agreement be adopted and approved.

8

9 Q. DOES THIS CONCLUDE YOUR PRE-FILED DIRECT TESTIMONY?

10 A. Yes, it does.

